TECHNICAL REVIEW DOCUMENT
For
MODIFICATION TO OPERATING PERMIT 96OPMR153

Brush Cogeneration Partners – Brush 2
Morgan County
Source ID 0870027

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Revised May and June 2003
Revised August 8, 2003 to reflect withdrawal of EPA's direct final rule for NSPS GG revisions

I. Purpose:

This document establishes the decisions made regarding the requested modifications to the Operating Permit for the Brush Cogeneration Partners Brush 2 facility. This document provides information describing the type of modification and the changes made to the permit as requested by the source and the changes made due to the Division's analysis. This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the information provided in the original request for modification submitted to the Division on March 14, 2003, various e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Permit Modification Request/Modification Type

The Operating Permit for the Brush Cogeneration Partners (BCP) Brush 2 facility was issued on February 1, 2000. Colorado Energy Management (CEM), the operators of the facility, submitted a request to modify the permit on March 14, 2003. The source indicated that the modification met the definition of a minor modification and requested that the modification be processed as a minor modification using the procedures in Colorado Regulation No. 3, Part C, Section X. The primary purpose of the modification was to combine the combustion turbine and duct burner fuel consumption limits and to increase the fuel consumption limit for the units. In addition, the source indicated that the duct burner was subject to the provisions of 40 CFR Part 60 Subpart Db but that the requirements had not previously been identified in permits issued for this unit. Finally, the source requested several changes to language in the permit which were identified in the draft permit submitted with the modification application. The Division's assessment of whether or not the requested modifications can be processed as minor modification is as follows:

Increase in Facility Fuel Use Limit

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures. Specifically, minor permit modifications "are not otherwise required by the Division to be processed as a significant modification" (Colorado Regulation No. 3, Part C, Section X.A.6). The Division requires that "any change that causes a significant increase in emissions" be processed as a significant modification (Colorado Regulation No. 3, Part C, Section I.B.36.h.(i)). According to Appendix D of Regulation No. 3 (Section I.F, revisions adopted July 15, 1993, Subsection I.G for modifications) the Division considers that a significant increase in emissions is the potential to emit above the PSD significance levels. The Brush 2 facility is considered a major stationary source for purposes of PSD review and any emission increase above the PSD significance levels would subject this facility to PSD review. The modification application included a demonstration that there was no significant increase in emissions. Baseline emissions were based on 2000 and 2001 actual emissions, which the source considers were representative of normal operations. The source did not consider 2002 emissions as representative as the turbine and duct burner were operated at a lower load and a reduced availability due to non-compliance issues related to the fuel consumption limits and the PM, PM_{10} and VOC emission limits. In addition, this modification represents a decrease in allowable emissions of PM, PM_{10}, NO_X and CO for the turbine and duct burner.

Addition of NSPS Db Requirements for Duct Burners

The Division requires that "any change that is considered a modification under Title I of the Federal Act" be processed as a significant permit modification (Colorado Regulation No. 3, Part C, Section I.B.36.h.(ii)). Appendix D of Regulation 3 describes more specifically what constitutes a modification under Title I of the Federal Act and Appendix D (Section I.F, revisions adopted July 15, 1993, Subsection I.G for modifications) indicates that a modification which triggers NSPS is considered a Title I modification. The duct burner is subject to the NSPS Db requirements and the source has requested that these requirements be identified in the operating permit with this modification. The duct burner was always subject to the requirements of NSPS Db, however, due to Division oversight, the NSPS Db requirements were not included in the construction permit issued for the turbine and duct burner or in the operating permit. Therefore, the Division considers that this modification does not trigger NSPS requirements, since the NSPS requirements always applied to the duct burner. Therefore, the Division considers that adding the NSPS requirements for the duct burner can be processed as a minor modification.

Other Changes

The source submitted a suggested draft operating permit with their minor modification application as required by Colorado Regulation No. 3, Part C, Section X.D.2. In this draft permit, the source identified other minor changes to the operating permit. The Division considers that these changes all meet the requirements for a minor permit modification. These changes are discussed in more detail in Section IV (Discussion of Modifications Made – Source Requested Modifications) of this document.

III. Modeling

The below table represents the change in emissions associated with these modifications:

Situation	Emissions (tons/yr)					
	PM	PM_{10}	SO_2	NO_X	VOC	CO
BCP PTE – Prior to Modification	48.7	48.7	2	117.4	26.7	80.8
BCP PTE– After Modification	9.9	9.9	1.3	110.7	32.3	48.2
Change in Emissions[1]	<38.8>	<38.8>	<0.7>	<6.7>	5.6	<32.6>
Turbine/Duct Burner/Engine PTE – After Modification	5.1	5.1	1.2	105.7	32	44
Turbine/Duct Burner Actual Emissions (2000 and 2001)[2, 3]	3.35	3.35	N/A	68.9	20.95	24.8
Change in Emissions[3]	1.75	1.75	N/A	36.8	11.05	19.2

[1]Values in brackets represent a decrease in emissions.
[2]Source indicated that 2002 emission data was not representative.
[3]N/A indicates that the actual-to-potential test was performed and test was not required since requested (PTE) emissions after the modification are below PSD significance levels. Note that an actual-to-potential test was not required for PM, PM_{10}, VOC and CO since requested emissions are also all below significance levels.

Modeling has been conducted for the Brush Cogeneration Facility (which includes the Brush 2 turbine/duct burner and the other 4 turbines and associated duct burners) several times over the last few years at the pre-modification emission levels. Since this modification does not result in the increase in any permitted emissions, no further modeling is required.

IV. Discussion of Modifications Made

<u>Source Requested Modifications</u>

The Division addressed the source's requested modifications as follows:

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- The permit contact was changed as requested by the source.

<u>Section I – General Activities and Summary</u>

- The source requested that the gallons/minute design rate of the cooling tower be revised to 29,900 gallons/minute.

<u>Section II – Specific Emission Units</u>

Section II.1 – Turbine, Duct Burner and Starter Engine

<u>Increase in Gas Throughput Limits and Changes in Emission Limitations</u>

The source requested that the fuel consumption limits for the turbine and duct burner be combined and that the limit be increased to 3,580 mmSCF/yr. Since the facility is a major stationary source, the source indicated that the net emission increase from the modification would not exceed the PSD significance levels. Actual emissions were based on 2000 and 2001 data. The source indicated that actual emissions from 2002 were not representative since the unit was run at lower loads and reduced availability in order to avoid violating the fuel consumption and particulate matter and VOC emission limits. Although the lower operating rate of this unit is not due to lower demand or mechanical problems with the turbine, the Division agrees with the use of 2000 and 2001 data as representative as it is expected that future operating levels will be at or above those in 2000 and 2001.

Actual emissions for NO_X and CO are based on continuous emission monitoring system (CEMS) data. The actual emissions provided in the modification application were not based on calendar year 2000 and 2001 emissions, but on December to November data. At the Division's request, the source submitted monthly CEMS data for calendar year 2000 and 2001 and those values (NO_X: 2000 – 75.6 tons/yr and 2001 – 62.2 tons/yr, CO: 2000 – 25.6 tons/yr and 2001 – 24 tons/yr) were used in the actual-to-potential test. The source requested a reduction in permitted emissions for NO_X and CO to keep the net emission increase of NO_X below significance levels. The requested emission levels are based on the average NO_X and CO emission factors determined from the CEMS data, the requested fuel consumption limit and the average heat content of the fuel. The requested NO_X emissions also included 5 tons/yr for the boilers (the current Title V operating permit identifies the NO_X limit for the turbine, duct burner, engine and boiler as a facility wide limit). The requested CO emission limit includes a 20%

contingency factor, but does not include the 4.2 tons/yr permitted emissions for the boilers. Note that since permitted CO emissions in the current permit are already below the significance level no reduction in potential emissions was necessary for CO.

Performance testing was conducted on the turbine and duct burner in January 2002. The source is electing to use emission factors from the performance test to estimate PM, PM_{10} and VOC emissions. The performance test was conducted on January 7, 2002 and was conducted with both the turbine and the duct burner operating (combined cycle operation). The source proposed to use the following emission factors:

Pollutant	Emission Factors (lbs/MMBtu)	Source
PM	0.0027	From performance test conducted 1/7/02, the average of 3 one-hr tests
PM_{10}	0.0027	
VOC	0.017	From performance test conducted 1/7/02, the highest 1-hr test (run 3)

Note that although the test was conducted with both the turbine and duct burner firing, the above emission factors shall be used when for both simple cycle (turbine only) and combined cycle (turbine and duct burner) operation.

The source requested revised emission limits for PM, PM_{10} and VOC based on the requested fuel consumption rate and the new emission factors. The source conducted an actual-to-potential test for PM, PM_{10} and VOC emissions. It should be noted that the source incorrectly based actual emissions on the emission factor in the current permit and the actual fuel consumption rate and therefore showed a decrease in actual emissions. The Division considers that the emission factor from the performance test represents what the emission levels always were from the unit. Therefore, the Division's analysis is based on the emission factors from the performance test and actual emissions. It should be noted that since requested emissions of PM, PM_{10} and VOC are below the significance levels, an actual-to-potential test was not necessary.

<u>Include NSPS Db Standards for Duct Burner</u>

The source indicated that the duct burner is subject to the requirements in 40 CFR Part 60 Subpart Db and these requirements had never been included in the construction permit or in the Title V operating permit for this facility. Therefore, the source requested that the NSPS Db NO_X limits be included in the revised operating permit.

The requirements in NSPS Subpart Db applies to the duct burner only. As far as emission limitations go, the Brush 2 duct burner is only subject to a NO_X emission limit. For compliance purposes, a duct burner can either conduct a one-time stack test or use a continuous emission monitoring system to demonstrate compliance with the NO_X emission limitation (per 40 CFR Part 60 Subpart Db § 60.46b(f), as adopted by reference in Colorado Regulation No. 6, part A). A performance test was conducted on February 11, 2003 and the test indicated that the unit was in compliance with the NSPS Db NO_X limit. Although the unit is equipped with a NO_X CEMS, NSPS Db does not require that duct burners be equipped with NO_X CEMS (per 40 CFR Part 60 Subpart Db § 60.48b(h), as adopted by reference in Colorado Regulation No. 6, Part A). Since a NO_X CEMS is not required for duct burners and since compliance with the NSPS Db NO_X limit was demonstrated with a performance test, the Division considers that the specific requirements for NO_X CEMS in NSPS Db do not apply to the Brush 2 duct burner. In addition, the reporting requirements in NSPS Db for units with CEMS also do not apply to the Brush 2 duct burner.

However, for purposes of periodic monitoring, the Division will require that BCP use their NO_X CEMS to monitor compliance with the NSPS Db NO_X limit. In order to simplify the monitoring requirements for the source, the permit will specify compliance with the NSPS Db NO_X limit will be monitored by comparing the average daily NO_X emissions, in lbs/mmBtu, to the NSPS Db NO_X limit. Since the NSPS Db NO_X limit is based on a 30-day rolling average, this compliance monitoring method is very conservative. The permit will also include provisions to manually calculate 30-day averages, in the event that a daily average NO_X value exceeds the NSPS Db limit. An 30-day average that exceeds the NSPS Db NO_X limit will be considered a violation of the NSPS Db NO_X limit.

The specific NSPS Db NO_X requirements that will be included in the revised operating permit are as follows:

- NO_X emissions shall not exceed 0.2 lbs/MMBtu (40 CFR Part 60 Subpart Db § 60.44b(a)(4)(i), as adopted by reference in Colorado Regulation No. 6, Part A).

- NO_X limits apply at all times including periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart Db § 60.44b(h), as adopted by reference in Colorado Regulation No. 6, Part A)

- Compliance with the NO_X limit shall be determined on a 30-day rolling average basis (40 CFR Part 60 Subpart Db § 60.44b(i), as adopted by reference in Colorado Regulation No. 6, Part A)

- The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month (40 CFR Part 60 Subpart Db § 60.49b(d), as adopted by reference in Colorado Regulation No. 6, Part A).

- All records required under this section shall be maintained for a period of 2 years (40 CFR Part 60 Subpart Db § 60.49b(o), as adopted by reference in Colorado Regulation No. 6, Part A).

  Note that the requirement to retain records for 2 years will be streamlined out of the permit, since Regulation No. 3, Part C, Section V.C.6 requires that records be retained for five (5) years.

Also, it should be noted that since the initial performance test has already been conducted, the performance test requirements in 40 CFR Part 60 Subpart Db §§ 60.46b(c) and (f) and reporting requirements in § 60.49b(b) have not been included in the revised operating permit. In addition, since the units commenced operation in 1994, the startup notice reporting requirements in 40 CFR Part 60 Subpart Db § 60.49b(a) will not be included in the revised operating permit.

Miscellaneous Changes to Turbine, Duct Burner and Starter Engine

The source requested that the requirement to use the highest reading recorded during the previous 30 day period in determining NO_X and CO emissions when the CEM is not operational (Section II, Condition 1.1.1) be replaced with the data replacement requirements in 40 CFR Part 75 and that the requirement for 90% monitor availability be removed (Section II, Condition 1.1.1).

The Division considers that using the data replacement procedures in 40 CFR Part 75, rather that the language included in the current operating permit (highest reading recorded during previous 30 day period) is acceptable and the permit has been revised as requested.

In regards to the requirement that monitor availability be at least 90%, the source suggested no alternative to this requirement. The Division considers that since the operating permit requires that the continuous monitoring system meet the requirements in 40 CFR Part 60 Subpart A § 60.13 (Section II, Condition 1.7.6), the requirement for 90% monitor availability conflicts with the requirement in § 60.13(e), which requires that the continuous monitoring system be operated at all times, except under certain conditions. Therefore, it was not appropriate for the Division to include the 90% requirement in the operating permit and the permit has been revised to remove the monitor availability requirement as requested by the source.

The source also requested that themethod to determine the Btu content of the gas be revised to allow that the Btu content be determined monthly based on analyses provided by the supplier and specified that the Btu content be based on the saturated higher heating value. This change has been made as requested.

Section II.3 – Cooling Tower

The source requested an increase in the water circulation rate and subsequently an increase in the PM and PM_{10} emission limits. In addition, the source has requested modifications to the method to determine the water circulation rate and the total dissolved solids concentration. In general, these changes will be made as requested by the source, however, there may be revisions to language to make the permit more consistent with the other operating permits issued for the Brush Cogeneration Facility.

Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments on other permits, to the BCP - Brush 2 Operating Permit with the source's requested modifications. These changes are as follows:

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- To be consistent with the other permits issued for the Brush Cogeneration Facility, the facility name is now indicated as "Brush 2" and the owner (under "issued to") was changed to "Brush Cogeneration Partners". In addition, the address under "issued to" was corrected.

- The citation (above "issued to" and "plant site location") on the page following the cover page provides the incorrect title for the state act. The title will be changed from "Colorado Air Quality Control Act" to "Colorado Air Pollution Prevention and Control Act". In addition, the dates were removed from the citation.

- Revised Responsible Official's title.

- Added language specifying that the semi-annual reports and compliance certifications are due in the Division's office and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications.

General

The headers were revised to place the facility owner on the first line on the left hand side and the facility name on the second line on the left hand side. To be more consistent with the permits issued for the other operating permits issued for the Brush Cogeneration Facility, the facility name is noted as "Brush 2" and the facility owner is indicated as "Brush Cogeneration Partners".

Section I –General Activities and Summary

- Added language to Condition 1.1 regarding the other turbines located at the Brush Cogeneration Facility and the turbine numbering scheme for this facility.

- Conditions 13 and 17 in Condition 1.4 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22. The renumbering changes were necessary due to the addition of the Common Provisions requirements in the General Conditions of the permit.

- Condition 1.6 was removed since the same language is in Condition 3.1.

- Revised the language in Condition 3.1 and added the operating permit number for the BIV – Brush 4 turbines. Revised the language in Condition 3.1 to more appropriately address the PSD status of the source. Reversed the order of Conditions 3.1 and 3.2.

- Based on comments made by EPA on another operating permit, the phrase "Based on the information provided by the applicant" was added to the beginning of Condition 4.1 (112(r)).

- Under pollution control device under the table in Condition 5.1 added "dry low NO_X combustion technology" for the turbine and "drift eliminators" for the cooling tower" to indicate that emissions are controlled.

- Added a "new" section 5 for compliance assurance monitoring. CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. Although the turbine is equipped with a dry low NO_X combustion system (DLN), DLN is not considered a control device as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since the DLN combustion system is considered inherent process equipment. Therefore, no emission units are subject to CAM.

<u>Section II – Specific Emission Units</u>

Section II.1 – Turbine, Duct Burner and Starter Engine

Most of the associated changes have been made in order to change the format for this permit in order to make it more consistent with the format for the permits issued for the other Brush turbines and to include requirements that may been previously overlooked. Specifically, the changes were made as follows:

- Grouped all NO_X, CO and SO_2 conditions together under one single condition (i.e. SO_2 limits are under Condition 1.3.).

- CEMS conditions were moved to a separate section of the permit (Section II.4). There are CEMS related conditions in Condition 1.1 and 1.11. The language in this section is similar to the CEMS requirement sections in the other operating permits issued for the Brush Cogeneration Facility.

- Added a specific condition to identify BACT for the turbine and duct burner. There is a similar condition in the operating permits issued for Brush 1 and 3 (96OPMR171) and Brush 4 (00OPMR224).

  The construction permit (91MR934-1) issued for the turbine, duct burner and engine was processed as a PSD permit. The construction permit included short term (BACT) emission limits for NO_X and CO and clearly identified what BACT was determined to be for NO_X (dry low NO_X combustion control), but did not specifically identify what the BACT for CO was. A review of the file indicates that BACT for CO was determined to be good combustion control practices. Although the construction permit identified what BACT was determined to be for NO_X, this information was never included in the operating permit. Therefore a condition ("new" condition 1.1) was added to indicate what the BACT determination was for both NO_X and CO.

  It should be noted that the preliminary analysis (dated January 28, 1992) for the original construction permit issuance indicated that PSD requirements only applied to NO_X and CO emissions. When the original construction permit was processed, emissions from Brush 2 were aggregated with Brush 1 and 3 (Colorado Power Partners (CPP), 96OPMR171) to determine PSD applicability, since the facilities were considered a single source and because the Division believed that the intent was to build the BCP facility when the construction permit for the CPP facility was applied for. In the preliminary analysis, the Division indicated that BACT only needed to be applied to those pollutants emitted in significant quantities (100 tons/yr), which were NO_X and CO. The 100 tons/yr is the major stationary source level for the BCP/CPP facility and the significance level for CO. Since the facility (BCP and CPP) came in as a major stationary source, BACT should be applied to the pollutant for which the facility is major for and any other pollutants whose emissions exceed the PSD significance levels. Based on the January 1992 preliminary analysis, requested emissions from CPP and BCP were 22.3 tons/yr of PM_{10} and 61.9 tons/yr of VOC, which were above the significance levels of 15 tons/yr for PM_{10} and 40 tons/yr of VOC. Therefore, BACT should have applied to PM_{10} and VOC. The Division considers that BACT for VOC would have been determined to be good combustion practices and BACT for PM_{10} would have been determined to be use of natural gas as fuel. The Division has not included a BACT emission limit for PM_{10} in other PSD permits issued for turbines, and so no BACT emission limit is necessary. The Division has included a BACT emission limit for VOC in PSD permits for turbines that were issued at a later date. However, since VOC CEMS would not be practical or required in this case, a VOC BACT limit would be rather meaningless. It should be noted that the recent stack testing done on this unit indicates VOC emissions at less than 3 ppmvd at 15% O_2.

  In processing the initial Title V permit application, the source requested an increase in the fuel consumption limits for the turbine and the starter engine and an increase in PM and PM_{10} emissions since the AP-42 emission factors had been revised. The Division had indicated that this revision would subject the unit to BACT for PM and PM_{10}. The source did not agree that BACT was triggered for these pollutants, since the increase in emissions due to the increase in fuel consumption was less than the significance level. However, the Division would have considered that the PM and PM_{10} emissions from the turbine were at the rate predicted by the revised AP-42 emission factors when the turbine first began operation and those rates were above the 25 ton/yr significance level for PM. The source submitted a BACT analysis for PM and PM_{10} in a letter received on June 30, 1998 and BACT for PM and PM_{10} was determined to be use of natural gas as fuel. As stated previously, Division has not included a BACT emission limit for PM or PM_{10} in other PSD permits issued for turbines, and so no BACT emission limit is necessary.

It should be noted that for the PSD construction permit issued for Brush 4, a modeling analysis, including PM_{10} emissions, was conducted for the Brush Cogeneration Facility.

- The emission limits identified in Section II.1 of the permit (turbine, duct burner and starter engine) are indicated as “facility wide” limits. The construction permits for the turbine, duct burner and engine (91MR934-1) included separate fuel consumption limits for the turbine, duct burner and engine and facility wide emission limits that applied to the boilers and the turbine, duct burner and engine. The construction permit for the boilers (91MR934-2) included the facility wide emission limits that were in 91MR934-1, additional emission limits for the boilers alone and fuel consumption limits for the boilers. No construction permit was issued for the cooling tower but the appropriate applicable requirements were directly incorporated into the operating permit. It is not completely clear under the emission calculation condition for the cooling tower (Condition 3.1) that these emissions must be summed with the turbine, duct burner, engine and boiler. Since there are separate emission limits for the cooling tower and boilers, it is not clear what the purpose of the facility wide limit is. Therefore, the turbine, duct burner and engine will have its own emission limit and there will be no facility wide limit identified in the permit.

- Emission factors for NO_X and CO for the engine were added to the permit. The permit did not previously identify emission factors for NO_X and CO. The emission factors are the same as those included in the permit for Brush 1 and 3. The NO_X emission factor is from the manufacturer (converted to lbs/gal, based on 600 hp and a fuel design rate of 32.2 lbs/gal) and the CO emission factor is from AP-42, Section 3.3 (dated 10/96), Table 3.3-1 (converted to lbs/Mgal based on a heat content of 137,000 Btu/gal).

  Note that the permit already included emission factors for PM, PM_{10}, VOC and SO_2 and these emission factors won’t be revised with this modification. The VOC emission factors were from the manufacturer (converted to lbs/gal, based on 600 hp and a fuel design rate of 32.2 lbs/gal). The PM, PM_{10} and SO_2 emission factors are from AP-42, Section 3.3.1 (dated 1/75). In the renewal for this operating permit, the Division will revise these emission factors to include the latest AP-42 emission factors, which are included in the operating permit for Brush 1 and 3.

- The Regulation No. 1 particulate matter emission limit does not appear to be correct and the numerical value has been corrected in this modification. In addition, it appears that this emission limit is only based on combined cycle operation (turbine and duct burner together), so the particulate matter limit for simple cycle operation (turbine alone) has also been added.

- The NSPS SO_2 requirements are not identified in the current permit correctly. Specifically, the NSPS allows the source to either meet the 150 ppm limit or the fuel sulfur limit. The Division has revised the language to indicate the appropriate NSPS GG SO_2 limits.

- The language in the current permit does not require any fuel sampling to monitor compliance with the NSPS GG SO_2 requirements, since natural gas is used as fuel. For purposes of monitoring compliance with the NSPS GG SO_2 requirements the Division has included language in the permit indicating that the natural gas used as fuel shall meet the definition of pipeline quality natural gas and that the source shall use the methods in 40 CFR Part 75, Appendix D, Section 2.3.1.4 to demonstrate that the fuel burned is pipeline quality natural gas.

  This language is consistent with the request for an alternative test method for monitoring the sulfur content of the fuel that the source submitted to EPA on September 26, 2002. Note that it is not clear whether EPA has approved this request.

  In addition, it should be noted that EPA had proposed revisions to NSPS GG (published in the April 14, 2003 Federal Register). The revisions were proposed as a direct final rule and if no adverse comments were received by May 14, 2003, the revisions would take effect on May 29, 2003. In these revisions, EPA intended to include many alternative monitoring options that have already been approved on a case-by-case basis. The proposed revisions to NSPS GG indicate that no fuel sampling is required for sources that use natural gas as fuel and the revisions include a definition of natural gas and methods to demonstrate that the gas used meets the definition of natural gas. Although these rules have been withdrawn, EPA has previously indicated in an August 14, 1987 memo that the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas can be waived. In addition, for other turbines burning pipeline quality natural gas (in accordance with the definition in 40 CFR Part 72), EPA has approved the use of the “Optional Sulfur Dioxide Emissions Data Protocol for Gas-Fired and Oil-Fired Units” of Appendix D of 40 CFR Part 75 as a custom fuel monitoring schedule for SO_2 (March 13, 2000 letter from John Hepola to Daniel Ewan, re “Approval of Alternative Monitoring for NSPS Subpart GG Pine Bluff Energy, LLC – Pine Bluff Energy Center Pine Bluff, Arkansas Operating Air Permit # 1822-AOP-R0”, Control

Number 0000015, from EPA Region 6). It should be noted that EPA had included test methods from 40 CFR Part 75 Appendix D in their proposed revisions.

- The current permit does not include the Reg 1 SO_2 requirement (0.8 lbs/MMBtu per Reg 1, Section VI.B.4.b.(i)) for the starter engine. This requirement has been included in the revised permit.

- Clarified the language in the permit regarding the NO_X and CO BACT limits. The averaging time is not really a 24-hr average, but a daily average, since these units do not run 24 hours per day.

- The definitions of startup and shutdown (CO BACT limit) were revised so as not to conflict with the startup and shutdown definitions in the state statutes. In addition, the shutdown definition was revised to indicate that a signal for shutting down has been sent. This is consistent with the definition of shutdown for Brush 1 and 3.

- The current permit did not include the Reg 1 30% opacity requirement, which applies during certain specific activities or the Reg 6, Part B 20% opacity requirement. As shown on the attached grid, none of the opacity requirements are more stringent at all times, therefore, all opacity requirements shall be included in the permit. It should be noted that the Reg 6, Part B 20% opacity requirement only applies to the turbine and duct burner, not to the engine.

- The periodic monitoring required for the starter engine was revised to be consistent with the language in the Brush 1 and 3 permit.

- The “good operating practices” language from 40 CFR Part 60 Subpart A § 60.11(d) was added to the NSPS General Provisions condition and the language in Condition 1.9 regarding operating equipment in accordance with manufacturer’s recommendations was removed.

Section II.2 – Boilers

- As discussed under the turbines, since upon issuance of the initial approval construction permit the boilers had separate emission limit, as well as a facility wide limit to which the turbine, duct burner starter engine and boilers were subject to. It is not clear what benefit is received in having the boilers subject to an individual emission limit as well as a facility wide emission limit. Therefore, since the facility wide emission limit has been removed and each emission unit or group of units is subject to its own emission limit. Therefore, since permitted emissions of PM_{10}, PM, SO_2 and VOC emissions are below APEN de minimis, these limits will be removed from the permit. Note however, that PM, PM_{10}, SO_2 and VOC emissions shall still be reported on any APENs submitted and are still subject to annual fees.

- The permit indicates that the boilers are subject to NSPS Dc and requires the source to certify that the boilers use only natural gas as fuel. The technical review document indicates that for boilers only burning natural gas as fuel the only applicable requirements for such units are the recording of fuel consumption daily and retention of records for 2 years (40 CFR Part 60 Subpart Dc §§ 60.48c(g) and (i)) and therefore there is no regulatory impact of the requirements and no requirements will be included in the operating permit. However, after further review, the Division believes that the daily recordkeeping requirement should be included in the permit. Note that the recordkeeping requirement will be streamlined out of the permit in favor of the recordkeeping requirements in Colorado Regulation No. 3, Part C, Section V.C.6.

- Added language to the permit, indicating how the numeric PM limit was determined.

- The "good operating practices" language from 40 CFR Part 60 Subpart A § 60.11(d) was added to the NSPS General Provisions condition and the language in Condition 2.7 regarding operating equipment in accordance with manufacturer's recommendations was removed.

- There is a condition (2.7) in the table that indicates that run-time hours shall be recorded monthly and the language in the text of Condition 2.7 does not reference recording operating hours. Therefore the language in the table regarding recording operating hours has been removed and as discussed above the language in Condition 2.7 has been removed.

- Added the Reg 1 30% opacity requirement.

- The boilers are subject to the requirements in Reg 6, Part B, Section II, specifically the particulate matter and opacity requirements. The Reg 6, Part B particulate matter requirements have been included in the permit shield under streamlined conditions. However, the Reg 6, Part B opacity requirement is not in the shield as a streamlined condition or in the current permit. As discussed under the turbine, duct burner and starter engine, no one opacity requirement (Reg 1 20%/30% and Reg 6, Part B 20%) is more stringent than the others at any one time (see attached grid), therefore all opacity requirements have been included in the permit.

<u>Section II.3 – Cooling Tower</u>

- Expanded the equation to calculate PM and PM_{10} emissions. The equation in the revised permit is the same as in the current permit, however, the expanded equation shows more clearly what the parameters the emissions are based on.

- No construction permit was issued for the cooling tower. The appropriate applicable requirements were directly incorporated into the operating permit and those requirements are being revised with this modification. Therefore, the following phrase was added to Conditions 3.1 and 3.2 as a citation for the authority to permit directly in the operating permit without issuing a construction permit "as provided for under the provisions of Colorado Regulation No. 3, Part A, Section I.B.36.h and Part C, Section X, based on the APEN submitted on March 14, 2003.

- The Reg 1 20% opacity requirement was not included in the permit for the cooling tower. Although the Division considers that it is unlikely that the cooling water tower would violate the 20% opacity requirement, this requirement must be included in the operating permit. Therefore, the Division considers that the cooling water tower is, in the absence of credible evidence to the contrary, in compliance with the 20% opacity requirement provided the cooling water tower and the associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

  Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling water tower. In addition, there is really no "startup" involved in operating a cooling water tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with this unit.

- Since compliance with the opacity requirement is based on drift eliminator maintenance, Condition 3.4 (drift eliminator inspection and maintenance) was removed.

<u>Section III – Permit Shield</u>

- The citation for the permit shield is incorrect. The reference to Part A, Section I.B.43 should be Part A, Section I.B.44 and the reference to Part C, Section XIII should be Part C, Section XIII.B.

- Based on comments made by EPA on another permit, the following statements were added after the introductory sentence in Section 1 "This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance".

- Based on comments made by EPA on another permit, the following phrase was added to the beginning of the introductory sentence "Based upon the information available to the Division and supplied by the applicant".

Section IV – General Conditions

- Added an “and” between the Reg 3 and C.R.S. citations in General Condition 3 (compliance requirements).

- Added language from the Common Provisions (new condition 3). With this change the reference to “21.d” in Condition 20 (prompt deviation reporting) will be changed to “22.d”, since the general conditions are renumbered with the addition of the Common Provisions.

- Removed the upset and breakdown provisions from Condition 4 (emergency provisions) since they are included in the Common Provisions.

- Effective July 1, 2001, the Division’s permit processing, emission and APEN fees were increased. Therefore, the language in Condition 7 (fees) was changed to remove the specified fee and cite the state statute for the appropriate fee. In addition, the state statute will be cited rather than Reg 3.

- The citation for the odor requirements was corrected. In addition, the phrase “Part A” was added to the citation for Condition 13 (odor). Colorado Regulation No. 2 was revised and a Part B was added to address swine operations. Colorado Regulation No. 2, Part B should not be included as a general condition in the operating permit.

- The citation in General Condition 16 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from “Reg 1” to “Reg 9”.

- Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 28.

Appendices

- First Page of Appendices – The phrase “except as otherwise provided in the permit” was added after the word “enforceable” in the disclaimer at the request of EPA.

- Appendix B and C were replaced with revised Appendices.

- The EPA addresses in Appendix D were corrected.

- Added Acronyms for PPM (parts per million), PPMV (parts per million, by volume) and PPMVD (parts per million, by volume, dry) to Appendix E.